From:	Secretary Spencer Abraham
To:	LNGStudy
Subject:	2012 LNG Export Study
Date:	Monday, February 25, 2013 4:00:34 PM
Attachments:	Letter_The Honorable Steven Chu.pdf

February 25, 2013

The Honorable Steven Chu
Secretary, Department of Energy
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

RE: 2012 LNG Export Study

Dear Secretary Chu,

Senate Energy and Natural Resources Committee Chairman Ron Wyden's January 10, 2013 letter to Energy Secretary Steven Chu[1] posed several thoughtful questions regarding the macroeconomic study of liquefied natural gas (LNG) exports prepared by NERA Economic Consulting ("NERA Study")[2].

To contribute to Chairman Wyden's stated goal of effectively evaluating "all LNG export applications – prior to the approval – to gauge whether each is in the public interest," I have prepared the following comments for your consideration regarding long-term forecasts of the Energy Information Administration (EIA), the implications of future fuel competition on electricity prices, and alternative uses for natural gas in the manufacturing and transportation sectors.

EIA Data and Forecast Considerations

Chairman Wyden, in his January 10, 2013 letter, notes that EIA has revised its "reference case" projection of future market conditions since the release of its 2011 *Annual Energy Outlook* (2011 AEO) used for baseline analysis in the NERA Study. This is correct, as EIA recently released its preliminary 2013

[1] Text at http://www.wyden.senate.gov/news/press-releases/wyden-highlights-flaws-in-doe-export-study-

[2] W. David Montgomery, et al., "Macroeconomic Impacts of LNG Export from the United States," NERA Economic Consulting, December, 2012, http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf.

Annual Energy Outlook (2013 AEO) on December 5, 2012. The issue raised is whether, in light of the new data contained in EIA's latest AEO analysis, the conclusions reached in the NERA study remain valid.

When comparing the reference cases of the 2011 AEO and 2013 AEO, it would be prudent to examine, in the aggregate, trends in supply, demand and international trade represented by each scenario. Moreover, the significant uncertainties associated with long-dated forecasts justify comparable consideration of EIA's reference cases for 2025 and outdated years beyond 2035.

Table 1 provides the relevant projections at both time horizons for comparison purposes.

TABLE 1 – COMPARISON OF EIA's AEO 2013 EARLY RELEASE AND AEO 2011 REFERENCE CASES

	Reference Case Target Year							
	2025				2035			
AEO	Dry Gas Production (quads)	Consumption (quads)	Net Imports (quads)	Dry Gas Production as % of Consumption	Dry Gas Production (quads)	Consumption (quads)	Net Imports (quads)	Dry Gas Production as % of Consumption
2011 [1]	24.60	25.73	1.13	95.6%	27.00	27.24	0.23	98.3%
2013 [2]	29.22	27.28	-1.56	100%	32.04	29.06	-2.53	100%
Change	18.78%	6.02%			18.67%	6.68%		

1 Source: EIA, *Annual Energy Outlook 2011 With Projections to 2035*, http://www.eia.gov/forecasts/archive/aeo11/pdf/0383(2011).pdf, p.115.

2 Source: EIA, *Annual Energy Outlook 2013 Early Release Overview*, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf, p. 15.

In its 2011AEO reference case, EIA projected that in 2025 U.S. natural gas consumption would total 25.67 quadrillion Btu ("quads") while domestic dry gas production would equal 24.60 quads. Net imports of 1.13 quads would be required to balance the market. By this estimate, domestic resources would satisfy only about 95.6% of domestic demand in 2025.

In its preliminary 2013 AEO reference case, though, EIA projects U.S. natural gas consumption of 27.28 quads compared to 28.65 quads of production, meaning that domestic resources would prove sufficient to satisfy 100% of demand. An additional 1.56 quads would be available for net export, both through pipelines in North America and as LNG trade, presumably inclusive of liquefaction and compression losses.

EIA's 2013 AEO reference case projects consumption in 2025 to be 6.02% higher compared to its 2011 AEO reference case for the corresponding year. However, U.S. dry gas production in 2025 is projected to increase by 18.78% in the 2013 AEO compared to the outlook two years prior. These revisions mean that EIA has raised its expectations for growth in domestic gas supply at approximately three times the rate of expected growth in domestic consumption since publication of the 2011 AEO.

A similar conclusion can be reached by examining EIA's 2011 AEO and 2013 AEO 2013 projections through 2035. In the 2013 AEO reference case, EIA has revised its projections for consumption upward by 6.68% relative to its 2011 AEO projections for 2035. However, projections for domestic gas production have been revised upward by 18.67% relative to the 2011 AEO forecast. Under the 2011 AEO, the U.S. would have domestic production sufficient to cover only 98.3% of consumption needs. Under the 2013 AEO scenario, the U.S. has domestic production sufficient to cover 100% of consumption, including demand growth in the electricity, industrial and transportation sectors, with an additional 2.53 quads available for export.

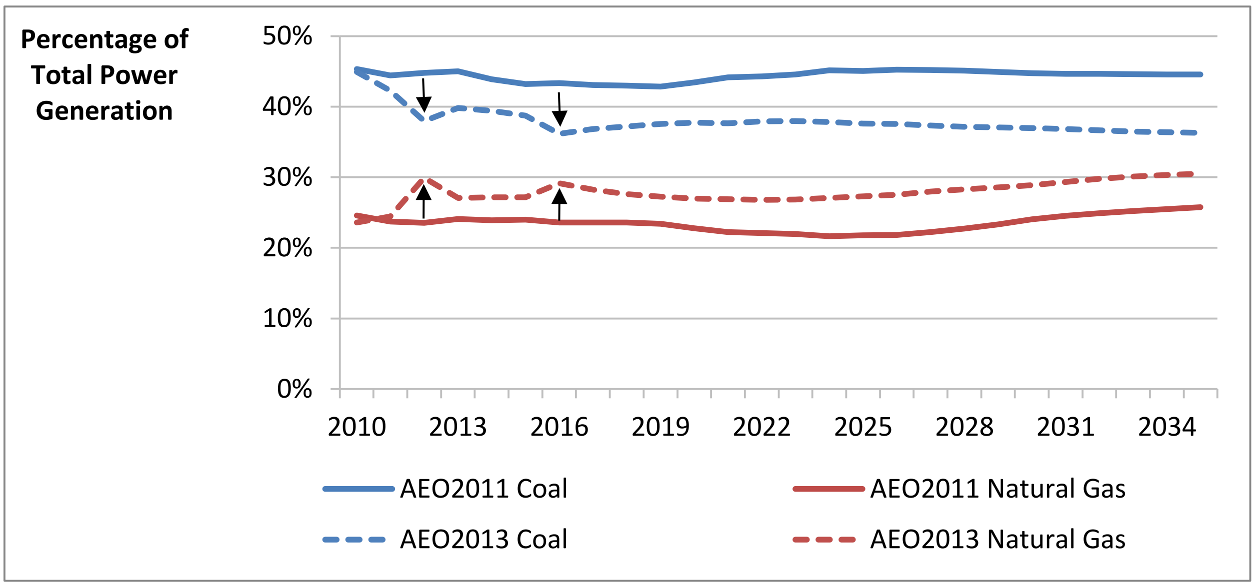
Chairman Wyden correctly recognizes that data revisions can influence conclusions and, indeed, the use of the 2011 AEO reference case in the NERA Study yields a moderately different set of conclusions relative to the use of a more recent market outlook. However, the directional change in supply and demand since the 2011 AEO forecast makes plain that the use of an older data set had, if anything, the impact of evaluating the macroeconomic consequences of LNG exports with a presumption of greater resource scarcity. In other words, if the NERA Study were to use the 2013 AEO forecast, its conclusions supporting the macroeconomic benefits of LNG exports would likely be stronger, not weaker.

Implications for the Electric Power Sector

Chairman Wyden, in his January 10, 2013 letter, further observes that EIA's 2013 AEO projects that natural gas will fuel a greater share of U.S. power generation in future years than projected in the 2011 AEO. This observation deserves some qualification.

Chart 1 below presents differences in the annual generation share (ie the generation by fuel source as a percentage of total U.S. power generation) between the two AEO reference cases.

CHART 1 – DIFFERENTIALLY GREATER AEO GAS-FIRED POWER REFLECTS PRICE, EPA POLICY CHANGES



SOURCES: "Table 8, Electricity Supply, Disposition, Prices, and Emissions," EIA, *Annual Energy Outlook 2013 Early Release,* data tables**,** http://www.eia.gov/forecasts/aeo/er/excel/aeotab_8.xlsx .

"Electric Power Projections for EMM Region, United States, Reference case," EIA, *Annual Energy Outlook 2011,* data tables, http://www.eia.gov/oiaf/aeo/tablebrowser/aeo_query_server/?event=ehExcel.getFile&study=AEO2011&region=3-0&cases=ref2011-d020911a&table=62-AEO2011&yearFilter=0.

The first set of black arrows in Chart 1 point to the year 2012 to highlight a difference between the generation mix EIA anticipated in the 2011 AEO (solid lines) and the generation mix that EIA reported within the historical component of its 2013 AEO projections (dashed lines).

The best explanation for the first divergence between the two outlooks would be the comparative costs of the competing fuels. EIA data show dramatically declining (-36.83%) natural gas costs for electric generators between 2010 and 2012 relative to modestly appreciating (+4.67%) coal costs during the same interval.[3]

The second set of black arrows in Chart 1 point to the year 2016, and highlight another difference between the 2011 AEO and 2013 AEO projections for the generation mix projections. These differences stem from a separate root cause. EIA uses a dynamic model called the National Energy Modeling System (NEMS) to prepare its *Annual Energy Outlooks*. The agency's reference cases are "policy-neutral," meaning that they are based on "Federal, State and local laws and regulations in [effect] at the time of the projection."[4] Because EPA did not finalize its Mercury and Air Toxics Standards (MATS) for electric generating units until December 2011, the impact of those standards, which go into effect in 2015, could not be included in the 2011 AEO dataset under EIA's principle of policy-neutrality. These changes however do impact the fuel mix assumptions within the 2013 AEO dataset.

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[3] "Table 3, Energy Prices by Sector and Source," EIA, Annual Energy Outlook Early Release, data tables, http://www.eia.gov/forecasts/aeo/er/excel/aeotab_3.xlsx.

[4] "The National Energy Modeling System: An Overview," EIA, http://www.eia.gov/oiaf/aeo/overview/.

Therefore, focusing on EIA fuel mix differentials relative to prior expectations may lead to misleading conclusions for several reasons.

First, the supply-side and demand-side factors highlighted by the sets of black arrows in Chart 1 could provoke future divergence from EIA's current generation mix projections. The 2012 divergence reflected, in large part, the unanticipated abundance of natural gas from unconventional formations. Technology continues to improve, and future production efficiencies and new resource finds will almost certainly augment current supply estimates.

Second, the MATS rule responsible for the 2016 divergence is unlikely to be the only environmental policy with the potential to shift the U.S. electric power generation mix. Other policy changes could potentially drive greater adoption of other fuels and differing compliance strategies, including renewable fuels and efficiency retrofits. For example, some generators might choose to preserve coal plants under greenhouse gas New Source Performance Standards (NSPS) for existing units by pairing them with wind or solar capacity for *pro rata* emission reductions of 100%, rather than the 50% achieved by natural gas substitution.

Third, end-user power prices are likely to be more relevant to end-user welfare impacts than the fuel generation mix itself. The cost of fuel is only one of several factors driving power prices. For example, increased utility investments in grid reliability, and retrofit costs to meet environmental compliance obligations, can also drive power prices higher.

Fourth, end-user power prices do not capture the whole story when evaluating end-user welfare – they are but one part of the equation. Residential end-users' welfare generally increases when energy costs as a share of disposable income decrease, i.e.

$$\text{income share of energy} = (\text{energy price}) * (\text{energy consumption}) / (\text{disposable income})$$

In other words, households with improving efficiency and/or growing disposable incomes could still be better off despite higher power prices. A similar relationship holds true for industrial end-users.

This may explain why the NERA study focuses on holistic measures of welfare that incorporate disposable income and/or revenue gains associated with greater domestic production. It also provides context to the NERA Study's conclusion that "the U.S. would experience net economic benefits from increased LNG exports" in all of the scenarios it studied.[5] A recent IHS study provides additional context for this assertion by linking unconventional production to economic benefits in non-producing states.[6] Thanks to economic growth resulting from energy production and LNG exports, households, businesses and governments will be better off when earnings grow faster than their energy costs.

Manufacturing Use of Natural Gas

I share Chairman Wyden's optimism that America's newfound energy abundance can unlock tremendous gains from our manufacturing sector. Chairman Wyden's letter cites a recent analysis by Dow Chemical of proposed manufacturing sector projects which is available for download from the website scribd.com.[7]

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[5] NERA Study, pp. 6-7 and 55.

[6] *America's New Energy Future, Volume 2: State Report, IHS, http://www.ihs.com/info/ecc/a/americas-new-energy-future-report-vol-2.aspx?ocid=anefvol2-21350:consulting:dm:0001.*

[7] "Industrial investments tied to surge in natural gas production," http://www.scribd.com/doc/115813231/Industrial-investments-tied-to-surge-in-domestic-natural-gas-production, accessed February 21, 2013.

This version of the Dow list includes 103 “newly-announced investments” which are alleged to require in excess of 6 Bcf/d of incremental natural gas demand. The study, however, does not provide the complete picture regarding the ability of the U.S. to meet its manufacturing sector’s needs for natural gas. For example, given that the list does not provide a breakdown of estimated natural gas demand per project, it is unclear what justifies the claim for an aggregated 6 Bcf/d of demand. Nor would it be realistic to assume that every “announced” project will be constructed in the future. It is the nature of competition in our market system that multiple parties will compete for an economic opportunity, but the hurdles of permitting, financing and commercialization impose natural limitations on which projects eventually reach a final investment decision. The lack of accompanying detail regarding these factors makes it difficult to assess the probability of success for the projects enclosed in the Dow list.

Nevertheless, what should be important to DOE’s consideration of this issue is that there are no apparent constraints on the availability of domestic supply that would prevent the manufacturing sector from reaching its full potential as provided in the Dow list.

Table 2, on the following page, compares the cumulative projected growth in domestic natural gas production provided in the 2013 AEO reference case with projected growth in the industrial sector.

TABLE 2 – PROJECTED GROWTH IN GAS PRODUCTION VS MANUFACTURING SECTOR GAS DEMAND

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Cumulative EIA year-on-year industrial demand growth (Bcf/d)[1]	0.17	0.10	0.12	0.91	1.41	1.91	2.12	2.35	2.50	2.62	2.79
Cumulative EIA year-on-year dry production growth (Bcf/d)[1]	2.5	2.74	2.33	2.83	5.85	6.58	8.00	9.06	9.89	10.81	12.03
Additional Production Growth vs Industrial Demand Growth	2.33	2.64	2.21	1.92	4.44	4.67	5.88	6.71	7.39	8.19	9.24

SOURCE:

[1] Table 13, "Natural Gas Supply, Disposition, and Prices," EIA, *Annual Energy Outlook Early Release*, http://www.eia.gov/forecasts/aeo/er/excel/aeotab_13.xlsx

Growth in domestic natural gas production is expected to significantly outpace growth in manufacturing demand, according to the 2013 AEO. Between 2012 and 2022, 12 Bcf/d of additional production is projected by EIA to reach the market, exceeding projected growth in the manufacturing sector by 9.2 Bcf/d over this same 10-year timeframe. In an optimistic scenario in which the manufacturing projects provided in the Dow list are fully commercialized, the 6 Bcf/d of additional demand alluded to in the study would be readily met by growth in domestic production. Thus, the 2013 AEO supports the conclusion that there are substantial resources available to meet growth in the domestic manufacturing sector as well as other uses, including exports as LNG. Hence, even under the optimistic scenario suggested by Chairman Wyden, a significant net surplus of natural gas production is projected to be available to meet growth in manufacturing and other uses.

It is also important for DOE to consider that the shale gas revolution has changed models and the real world alike by creating a U.S. natural gas market situation where supply is likely to remain demand-limited for the foreseeable future. For example, MIT's 2011 *Future of Natural Gas* report offers a supply curve that remains relatively flat between a price range of $4/MMBtu and $6/MMBtu at volumes up to 1,000 Tcf.[8] The National Petroleum Council's 2011 *Prudent Development* study highlights how new technologies could extend supply within this price range by an incremental 500 Tcf or more.[9]

Demand-limited supply of this scale makes difficult a precise analysis of the energy requirements associated with LNG liquefaction and CNG compression. In this respect, the effect of improving extraction technologies and best practices in the upstream is critical. Prevailing prices of natural gas at the Henry Hub remain below the $4/MMBtu bottom of the range identified by MIT, and yet U.S. natural gas supply continues to grow.[10]

The downside of demand-limited supply is that producers may be unwilling to commit additional capital to develop new capacity during periods of uncertain demand. The demand-limited nature of the U.S. natural gas market means that manufacturers could be better served by looking for ways to encourage producers to continue to invest in domestic resources. The recent history of natural gas production in the Rocky Mountains offers a useful example.

The Rockies Express pipeline transports natural gas more than 1,600 miles from Colorado to Ohio, connecting the vast resources in the Rocky Mountain region to industrial and residential consumers in the Midwest. Before the pipeline became fully operational in November 2009, Rocky Mountain producers encountered periods when supply exceeded takeaway capacity, resulting in "stranded" resources and forcing sales of natural gas at deep discounts to prices in the Gulf Coast producing region.[11]

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[8] *The Future of Natural Gas,* MIT, p. 39, http://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

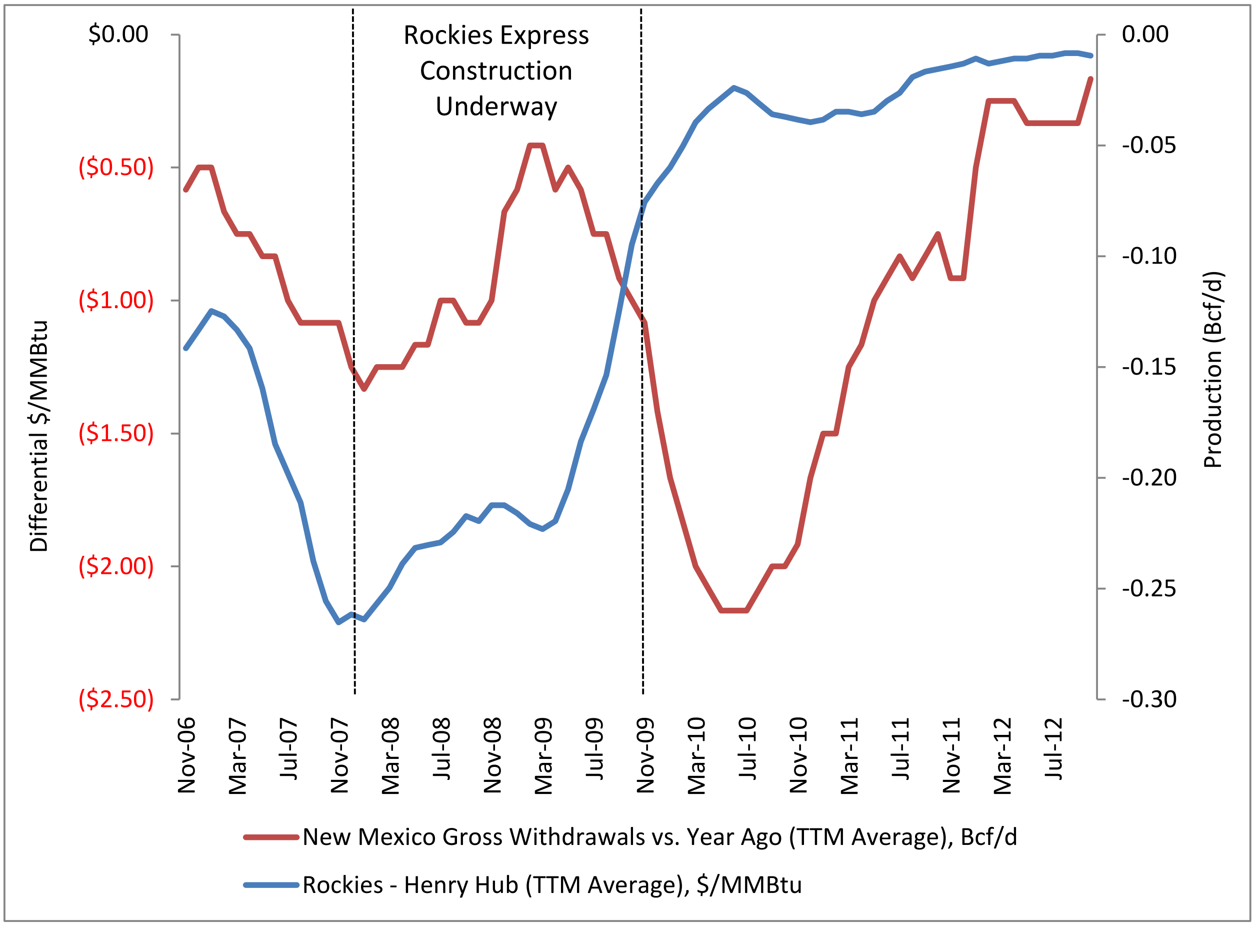
[9] Prudent Development, National Petroleum Council, p. 45, http://www.npc.org/reports/NARD/NARD_Resource_Supply.pdf.

[10] Gross withdrawals of U.S. natural totaled 83.54 Bcf/d in November 2012, according to EIA's Form-914 Survey of domestic gas producers, the highest withdrawal level in U.S. history and approximately 1 Bcf/d higher than reported production of 82.55 Bcf/d in November 2011. See EIA, *Monthly Natural Gas Gross Production Report,* http://www.eia.gov/oil_gas/natural_gas/data_publications/eia914/eia914.html (accessed February 22, 2013).

[11] Between 2000 and 2007, annual wellhead prices in Wyoming averaged between 9.2% and 33.8% lower than corresponding annual wellhead prices in Louisiana. See EIA, *Natural Gas Prices* http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

Chart 2, below, graphs EIA production data for New Mexico against historical spot prices for the Rockies computed by Bloomberg, averaging current month vs. year-ago levels over a trailing twelve-month (TTM) period to norm for seasonal variation.

CHART 2 – ROCKIES EXPRESS CLOSED REGIONAL DIFFERENTIALS AND ENCOURAGED SUPPLY



Sources:

● Bloomberg NGRMRAVG Index, which averages Rocky Mountain spot natural gas prices in Wyoming, Colorado and New Mexico, spot prices averaged on a monthly basis.

● "Estimated EIA-914 Gross Withdrawals by Area by Month, Bcf/d," EIA, http://www.eia.gov/oil_gas/natural_gas/data_publications/eia914/bestestofgrosswd.xls.

Prior to completion of the Rockies Express pipeline, New Mexico withdrawals trended in line with price differentials relative to the Henry Hub – falling prices correlated with falling production. During the final months of pipeline construction, however, Rockies price differentials closed dramatically, narrowing from historic discounts in the $1.50-$2.00/MMBtu range to near-parity with the Henry Hub. This contributed to the recovery of production in the months following the 2009 trough.

When considering the public interest implications of LNG exports, it would benefit DOE to look beyond prices to the broader question of supply stability. This example is particularly apt given the present natural gas market environment. While New Mexico production fell throughout the period in question, the demand (and price) stability conferred by the Rockies Express project slowed and stabilized the rate of decline. By connecting the U.S. natural gas market to the world, LNG exports have the potential to deliver the same kind of supply and price stability for the manufacturing sector.

Transportation Use of Natural Gas

In his letter, Chairman Wyden also articulates his concern that natural gas export demand could negatively impact natural gas transportation applications. An analysis of the data, however, suggests that such an outcome is very unlikely.

Chairman Wyden cites an estimate of 600,000 barrels per day of diesel that could be potentially displaced by 3.3 Bcf per day of natural gas for use in transportation. This estimate appears to assume LNG-for-diesel substitution without any compression or liquefaction losses. A typical 18-wheeler travels an average of about 65,000 miles per year,[12] at an average efficiency of about 5 miles per gallon.[13] This means a typical long-haul freight truck uses 13,000 gallons per year of diesel fuel, or approximately 35.6 gallons (0.85 barrels of oil equivalent) per day.

Based on these estimates, it would require the manufacture, sale and deployment of approximately 707,538 new LNG trucks to reach the 600,000 barrels per day of diesel displacement referenced by Chairman Wyden, or the replacement of approximately 28% of the 2.55 million heavy-haulers on the road today.[14] This scenario is possible, but does not seem very realistic. Absent a severe oil shock, seven years would be a tight window for an infrastructure shift of this scale, even if truck manufacturers were mass-producing LNG rigs today.

Expectations for future diesel and natural gas prices suggest the potential for fuel cost savings in the transportation sector by converting commercial trucks to natural gas. According to EIA's 2013 AEO, diesel costs for the transportation sector in 2013 are projected to average $25.39 per MMBtu, or $3.47 per diesel gallon-equivalent (DGE), compared to natural gas costs of $16.41 per MMBtu, or $2.58 per DGE. These prices would imply a fuel-switching benefit of $8.98 per MMBtu, or $0.89 per DGE, inclusive of liquefaction and compression losses. Based on average consumption of 13,000 gallons of diesel per year in freight trucks, this would equate to fuel savings of about $11,564 per truck per year in 2013. As shown in Table 3, the discounting of natural gas compared to diesel prices is expected to grow in the near future, thereby expanding the fuel savings benefits resulting from conversion to natural gas. By 2020, annual fuel savings of about $14,736 per vehicle is projected, assuming average consumption of 13,000 gallons of diesel per year.

[12] Oak Ridge National Laboratory, *2011 vehicle Technologies Market Report,* February 2012, p. 78, http://cta.ornl.gov/vtmarketreport/pdf/2011_vtmarketreport_full_doc.pdf.
[13] U.S. Department of Energy, Transportation Energy Data Book, Chapter 5 – Heavy Duty Vehicles and Characteristics. Estimate derived from Table 5.2 *Summary Statistics for Class 7-8 Combination Trucks, 1970-2010*, 5.10 *Effect of Terrain on Class 8 Truck Fuel Economy*, and 5.11 *Fuel Economy for Class 8 Trucks as a Function of Speed and Tractor-Trailer Tire Combination,* http://cta.ornl.gov/data/chapter5.shtml
[14] U.S. Department of Transportation, Federal Highway Administration, *Highway Statistics 2010, Annual Vehicle Distance Traveled in Kilometers and Related Data – 2010.* There were 2,552,865 registered combination trucks in 2010. http://www.fhwa.dot.gov/policyinformation/statistics/2010/vm1m.cfm

However, the potential financial benefits of switching diesel rigs to LNG must be weighed against the considerable initial investment in equipment and labor required to convert the trucks. The cost to modify a freight truck to run on LNG from diesel is about $60,000 per truck.[15] Taking into account EIA's projected price differentials at an 8% cost of capital, the net present value (NPV) of this $60,000 investment doesn't become positive until 2019, as shown in Table 3.

TABLE 3 – NET PRESENT VALUE OF 18-WHEELER DIESEL-TO-GAS SWITCHING GOES POSITIVE IN 2019

	2013	2014	2015	2016	2017	2018	2019	2020
Diesel, $/MMBtu [1]	$25.39	$25.42	$25.99	$26.84	$27.82	$28.79	$29.81	$30.68
Diesel, $/DGE	$3.47	$3.47	$3.55	$3.66	$3.80	$3.93	$4.07	$4.19
Natural Gas, $/MMBtu [1]	$16.41	$16.51	$16.77	$17.48	$17.96	$18.57	$19.04	$19.46
Natural Gas, $/DGE	$2.58	$2.59	$2.63	$2.74	$2.82	$2.92	$2.99	$3.05
Benefit per DGE	$0.89	$0.88	$0.92	$0.92	$0.98	$1.01	$1.08	$1.13
Benefit per Year (13,000 gpy)	$11,564	$11,410	$11,895	$11,949	$12,703	$13,191	$14,048	$14,736
NPV of incremental $60,000 (5Y, 8%)	($12,639)	($11,437)	($9,401)	($7,219)	($4,205)	($1,078)	$2,128	$5,167

[1] Source: "Energy Prices by Sector and Source," EIA, *Annual Energy Outlook 2013 Early Release* data tables*:* http://www.eia.gov/forecasts/aeo/er/excel/aeotab_3.xlsx.

Some fleet operators may evaluate their investments over longer time horizons, improving the NPV profile, while others may have lower costs of capital. Nevertheless, a scenario under which LNG trucks generate the equivalent of 3.3 Bcf/d of incremental U.S. natural gas demand would require immediate and wide-scale adoption. This ignores that manufacturers have yet to achieve scale economies that would

[15] National Petroleum Council, *Advancing Technology for America's Transportation Future*, *Figure 3-14, Estimated Retail Price Equivalent of Class 7&8 Combination Diesel and Natural Gas Trucks – Reference Case*, August 2012, Chapter 3, p 15-16.

reduce the up-front $60,000 price for modifications, or that governments have yet to provide subsidies that would reduce this cost.

Moreover, even if manufacturers and lawmakers were to devise and execute successful transformation plans, replacing diesel demand with natural gas has the unintended consequence of augmenting the domestic supply of diesel fuel. Each incremental barrel of displaced diesel fuel would potentially erode the diesel-to-gas premium and deter future NGV adoption.

Chairman Wyden further cites an October 9, 2012 *Houston Chronicle* article[16] that outlines diesel-to-natural gas conversion opportunities for freight rail. Here, too, attractive reductions in fuel spending will be offset by significant up-front capital costs for the foreseeable future. The article quotes conversion costs of between $600,000 and $1 million per locomotive and new locomotive purchases at $2 million apiece. Although some portion of freight rail traffic could switch over to natural gas, a cursory break-even analysis suggests widespread adoption to be exceedingly unlikely.

The American Association of Railroads (AAR) website counts 24,250 Class I (freight) locomotives operating in 2011, the most recent year for which data are publicly available, and 23,893 Class I locomotives operating in 2010.[17] The most recent *Transportation Energy Data Book* published by Oak Ridge National Laboratory (ORNL) estimates that in 2010, diesel fuel consumption for Class I (freight) totaled approximately 229,600 barrels per day.[18] Together, these data suggest "average" freight rail fuel consumption of 9.6 barrels (403 gallons) of diesel per locomotive per day, or 147,168 gallons per year.

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[16] Zain Shauk, "Natural gas could be cheaper way to run a railroad," *Houston Chronicle*, October, 9, 2012, http://www.chron.com/business/energy/article/Natural-gas-could-be-cheaper-cleaner-way-to-run-3933795.php.

[17] "Class I Railroad Statistics," American Association of Railroads, January 13, 2013. https://www.aar.org/StatisticsAndPublications/Documents/AAR-Stats-2013-01-10.pdf .

[18] "Table 1.17, Transportation Petroleum Use by Mode, 2009–2010a, Thousand barrels," Oak Ridge National Laboratory, *Transportation Energy Data Book,* http://info.ornl.gov/sites/publications/files/Pub37730.pdf.

Table 4 provides a similar NPV analysis of the costs and benefits of converting diesel locomotives to LNG, and considers a range of up-front conversion costs between $600,000 and $1 million per locomotive. At a $600,000 capital cost, an average investment in natural gas engines could pay off (ie demonstrate a positive NPV) as early as 2016. At a cost of $1 million apiece, however, the NPV for conversion to an LNG-fueled locomotive remains negative through 2020, indicating that such an investment would lose money for operators for the foreseeable future. As a result, it would seem incremental natural gas demand from freight rail is likely to remain limited until conversion costs for existing engines or new locomotive costs decline substantially.

TABLE 4 – NET PRESENT VALUE OF LOCOMOTIVE DIESEL-TO-GAS SWITCHING

	2013	2014	2015	2016	2017	2018	2019	2020
Diesel, $/MMBtu [1]	$25.39	$25.42	$25.99	$26.84	$27.82	$28.79	$29.81	$30.68
Diesel, $/DGE	$3.47	$3.47	$3.55	$3.66	$3.80	$3.93	$4.07	$4.19
Natural Gas, $/MMBtu [1]	$16.41	$16.51	$16.77	$17.48	$17.96	$18.57	$19.04	$19.46
Natural Gas, $/DGE	$2.58	$2.59	$2.63	$2.74	$2.82	$2.92	$2.99	$3.05
Benefit per DGE	$0.89	$0.88	$0.92	$0.92	$0.98	$1.01	$1.08	$1.13
Benefit per Year (153,000 gpy), $000	$136	$135	$140	$141	$150	$156	$166	$174
NPV of incremental $600,000 (5Y, 8%), $000	($42)	($27)	($3)	$22	$58	$95	$133	$168
NPV of incremental $1,000,000 (5Y, 8%), $000	($442)	($427)	($403)	($378)	($342)	($305)	($267)	($232)

[1] Source: "Energy Prices by Sector and Source," EIA, *Annual Energy Outlook 2013 Early Release* data tables: http://www.eia.gov/forecasts/aeo/er/excel/aeotab_3.xlsx.

Taken together, both NPV analyses suggest that growth in transportation demand for natural gas isn't likely to materially accelerate before the end of this decade, thus, validating EIA's current projections.

Conclusion

Senate Energy and Natural Resources Committee Chairman Ron Wyden's January 10, 2013 letter posed several thoughtful questions for consideration by DOE of the NERA Study. The concerns raised, however, do not negate the economic benefits resulting from LNG exports identified by the NERA Study. Updates to EIA's 2013 AEO forecast demonstrate that expectations for growth in domestic natural gas production are far outpacing expected growth in domestic demand. This additional supply growth will be more than sufficient to accommodate potential incremental consumption in the manufacturing sector identified by Sen. Wyden. Additional supply resources will also be more than sufficient to satisfy incremental growth in the transportation sector, though growth will likely be less aggressive than suggested by Sen. Wyden. In summary, the updated outlook provided by EIA's 2013 AEO makes clear that the macroeconomic benefits of LNG exports demonstrated by the NERA Study would likely be stronger, not weaker, were NERA to again model the macroeconomic implications of LNG exports.

Therefore, based on the NERA study and the data trends contained in the 2013 AEO, there is a clear net benefit associated with the export of US natural gas. For that reason the Department of Energy should continue to move forward and issue export permits for gas so that America's businesses, workers, and trade partners may reap the benefits of this economic activity.

Respectfully submitted,

Spencer Abraham

Honorable Spencer Abraham